

Exhibit No.: _____
Application: A.25-09-XXX
Witness: M. Schmidt-Pines
Chapter: 9a

PREPARED DIRECT TESTIMONY OF MARJORIE SCHMIDT-PINES
ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY
AND SAN DEIGO GAS & ELECTRIC COMPANY
(COST ALLOCATION AND LONG RUN MARGINAL COST STUDY)

September 30, 2025
(Redlined dated June 9, 2026)

TABLE OF CONTENTS

	<u>Page</u>
I. PURPOSE	1
II. OVERVIEW OF COST ALLOCATION	2
III. COST ALLOCATION PRINCIPLES	3
IV. COST ALLOCATION METHOD PROPOSED FOR SOCALGAS AND SDG&E	4
V. SOCALGAS CUSTOMER-RELATED MARGINAL UNIT COST	6
A. Marginal Capital Cost.....	6
1. MSA Costs	7
2. Service Line Costs.....	7
B. Marginal Direct O&M Costs	8
1. Customer Services O&M Costs	8
2. Customer Accounts O&M Costs.....	9
3. Meters and Regulators O&M Costs	10
4. Service Lines O&M Costs	11
5. Customer Services and Information Costs.....	11
C. Calculation of Customer-Related Marginal Unit Cost and Marginal Cost Revenue	11
VI. SOCALGAS MEDIUM AND HIGH PRESSURE DISTRIBUTION-RELATED MARGINAL UNIT COSTS	13
A. Medium Pressure Distribution Marginal Unit Cost and Marginal Cost Revenue	13
1. Marginal Capital Cost	13
2. Marginal Direct O&M Costs.....	15
3. Calculation of Medium Pressure Distribution Marginal Unit Cost and Marginal Cost Revenue	15
B. High Pressure Distribution Marginal Unit Cost and Marginal Cost Revenue	16
VII. SOCALGAS MARGINAL COST ESTIMATION FACTORS.....	18
A. Real Economic Carrying Charge (RECC) Factors	18
B. O&M Loaders	19
C. A&G Loading Factors	20
1. General Plant Loading Factor	20

2.	M&S Loading Factor	21
VIII.	RESULTS OF THE SOCALGAS COST ALLOCATION STUDIES	22
IX.	COMPARISON OF SOCALGAS PROPOSED COST ALLOCATION TO CURRENT COST ALLOCATION	29
X.	SDG&E CUSTOMER-RELATED MARGINAL COSTS.....	31
A.	Marginal Capital Costs	31
B.	Marginal Direct O&M Costs	32
C.	O&M Loaders.....	34
D.	Fully Loaded Customer-Related LRMC	34
XI.	SDG&E MEDIUM PRESSURE AND HIGH-PRESSURE DISTRIBUTION- RELATED MARGINAL COSTS.....	35
A.	Marginal Direct O&M Costs	35
B.	Marginal Direct O&M Costs	36
C.	O&M Loaders.....	37
D.	Fully Loaded Distribution LRMC	37
XII.	SDG&E MARGINAL COST ESTIMATION FACTORS	39
A.	Real Economic Carrying Charges (RECC)	39
B.	Marginal O&M Loading Factors	40
1.	A&G Loading Factor	40
2.	General Plant Loading Factor	42
3.	M&S Loading Factor	43
XIII.	SDG&E ALLOCATED BASE MARGIN.....	44
XIV.	COMPARISON OF SDG&E PROPOSED COST ALLOCATION TO CURRENT COST ALLOCATION	48
XV.	QUALIFICATIONS.....	50

1 **CHAPTER 9**

2 **PREPARED DIRECT TESTIMONY OF MARJORIE SCHMIDT-PINES**

3 **(COST ALLOCATION AND LONG RUN MARGINAL COST STUDY)**

4 **I. PURPOSE**

5 The purpose of my testimony is to present the allocation of the authorized revenue
6 requirements to customer classes for Southern California Gas Company (SoCalGas) and San Diego
7 Gas and Electric (SDG&E). My testimony provides Customer-related, Medium Pressure
8 Distribution-related, and High-Pressure Distribution-related marginal unit costs and marginal cost
9 revenue, using the Long Run Marginal Cost (LRMC) method. The LRMC method refers to the
10 incremental cost to serve one additional unit in the long run; such a unit cost is called the marginal
11 unit cost.

12 My testimony also presents the total allocation of SoCalGas’s authorized base margin
13 revenue requirement, which combines the results of my LRMC analysis for Customer-related,
14 Medium and High Pressure Distribution -related costs, and which incorporates inputs from
15 witnesses Frank Seres and Marjorie Schmidt-Pines (Chapter 8) on Transmission-related and
16 Storage-related costs, as well as from witness Michael Foster (Chapter 12) on the Natural Gas
17 Vehicle (NGV) compression adder costs.

18 These LRMC updated studies are in compliance with CPUC Decision (D.) 24-07-009,
19 Ordering Paragraph (OP) 2. OP 2 states that the “all party settlement [...] attached to this decision
20 as Attachment A is approved and adopted without modification.”¹ Attachment A to D.24-07-009,
21 states in relevant part that “The next Cost Allocation Proceeding application will contain, at a
22 minimum, a fully embedded cost study based on 2024 FERC Form 2, as well as a benchmark cost

¹ D.24-07-009 at 35 (OP 2).

1 allocation utilizing Long Range Marginal Cost (LRMC) studies for the customer-related and
2 distribution functions. The benchmark cost allocation may leverage underlying LRMC data
3 presented in this cost allocation proceeding, updated to account for changes in line extension
4 allowance policy, loaders, and demand projections, and scaled to representative dollars in the
5 corresponding test year.”²

6 **II. OVERVIEW OF COST ALLOCATION**

7 Cost allocation refers to the process of determining the cost of each utility function and
8 allocating these functional costs to the customer classes. My testimony results in the allocation of
9 Base Margin³ revenue requirements across customer classes. This cost allocation is conducted by
10 first allocating the authorized revenue requirement to the functions performed by SoCalGas in order
11 to provide natural gas service. These functions are:

- 12 (i) Customer-related (service lines that deliver gas from the distribution main to
13 the end-use customers’ home or business), regulators (adjust gas pressure),
14 meters (measure gas consumed), customer support functions);
- 15 (ii) Medium Pressure Distribution System (mains lines that operate at medium
16 pressure and transport gas to service lines);
- 17 (iii) High Pressure Distribution System (mains lines that operate at high pressure
18 and transport gas to service lines and medium pressure pipelines);

² D.24-07-009, Attachment A, section II (A)(6).

³ SoCalGas’s Base Margin is authorized in a General Rate Case (GRC). Pipeline Safety Enhancement Plan (PSEP) cost components that are not in Base Margin are not included in the LRMC and Embedded Cost studies and they are functionally allocated to High Pressure Distribution and Transmission functions per D.14-06-007 and D.16-12-063. PSEP included in Base Margin are part of the Embedded Cost Study for Transmission and LRMC Study’s High Pressure Distribution functions. AB32 Administrative fees (CARB fee) are allocated on an Equal Cents Per Therm (ECPT).

- 1 (iv) Local Transmission System (large pipelines that transport supplies from the
- 2 backbone transmission system to distribution and to service lines);
- 3 (v) Backbone Transmission System (large pipelines that take supplies from
- 4 interstate pipelines to the local transmission system); and
- 5 (vi) Storage (injection, inventory, and withdrawal).

6 Once the functional allocation is complete, the cost of each function is then allocated to each
7 customer class. The customer classes are:

- 8 (i) Core (residential, commercial/industrial, natural gas vehicle (NGV), gas air
- 9 conditioning, gas engine);
- 10 (ii) Noncore (commercial/industrial, electric generation, wholesale, enhanced oil
- 11 recovery); and
- 12 (iii) Other (backbone transportation service).

13 Finally, I present total cost allocations among all customer classes in Tables 12 and 27.

14 **III. COST ALLOCATION PRINCIPLES**

15 In determining cost allocation, the following principles are followed by SoCalGas and
16 SDG&E: allocate costs to customer classes based on cost causality and maintain consistency with
17 the existing practices whenever possible. The fundamental principle applicable to these LRMC cost
18 studies, for purposes of allocating costs to customer groups, is the concept of cost causation. Cost
19 causation seeks to determine which customer or group of customers causes the utility to incur
20 particular types of costs. The essential element in the selection and development of a reasonable
21 cost allocation methodology is the establishment of relationships between customer requirements,
22 load profiles, usage characteristics, and the costs incurred by the utility in serving those
23 requirements. A cost allocation based on cost causation therefore seeks to present cost-based rates.

1 **IV. COST ALLOCATION METHOD PROPOSED FOR SOCALGAS AND SDG&E**

2 SoCalGas proposes the Embedded Cost method for all functional categories -
3 Transmission, Storage, Customer-related, Medium Pressure Distribution-related, and High Pressure
4 Distribution-related - for the reasons presented in the direct testimony of Frank Seres and Marjorie
5 Schmidt-Pines (Chapter 8). This is especially true since the Long Run Marginal Cost (LRMC) study
6 is based on the cost of the last marginal unit. The residential cost has significantly decreased with
7 the capital cost going to zero.⁴

8 LRMC refers to the incremental cost to serve one additional unit in the long run; such a unit
9 cost is called marginal unit cost. The cost causation unit is called a marginal demand measure. The
10 consolidated marginal demand measures are presented in the testimony of Eduardo Martinez
11 (Chapter 5). The LRMC-based functional revenue (i.e., marginal cost revenue) is derived by
12 multiplying the marginal unit cost by the number of marginal demand measures (MDM). For
13 Customer-related costs, the marginal demand measure is the number of customers. For Medium
14 Pressure Distribution-related and High Pressure Distribution-related costs, the marginal demand
15 measures are peak day demand⁵ and peak month demand,⁶ respectively.

16 In this Cost Allocation Proceeding (CAP), SoCalGas LRMC study reflects 2021 actual costs
17 and allocations based on 2021 underlying activities. The O&M loaders which are based on 2024
18 actual costs. The demand in the Distribution studies is updated to reflect historical data through
19 2024 and the CAP forecast. These costs are escalated to 2027 dollars to reflect SoCalGas costs for

⁴ Line Extension Allowance for residential customers is zero. SoCalGas Rule No. 20, C2, SDG&E Rule No. 15, C3.

⁵ Peak Day Demand is forecast to be in December. *See* direct testimony of Eduardo Martinez (Chapter 2).

⁶ Peak Month is defined as December. *See* Chapter 2 (Martinez).

1 the first year of the new CAP cycle.⁷ For the Customer-related and Medium and High Pressure
2 Distribution-related functions, the marginal unit costs are then multiplied by the forecasted MDM to
3 determine the marginal cost revenues.

4 Each functional marginal unit cost consists of two components: a capital cost component
5 and an operations and maintenance (O&M) cost component. The capital cost component reflects
6 the capital investment required to serve an additional unit. Customer-related capital costs are
7 associated with service lines as well as meters and regulators (collectively called meter set
8 assemblies, or MSAs). For Customer-related costs, this is the cost of serving an additional
9 customer. Marginal Customer-related capital costs have been developed using the Rental method,
10 adopted in the last CAP, which reflects the annualized capital cost of hooking up an additional
11 customer.

12 For Medium and High Pressure Distribution-related costs, LRMC represents the cost of
13 providing an additional increment of gas throughput⁸ through the distribution system. Marginal
14 demand capital costs have been developed using linear regression models to determine the
15 relationship between demand growth and investments over a 15-year period spanning historical and
16 forecast periods.⁹

17 O&M costs for both Customer-related and Medium and High Pressure Distribution-related
18 functional categories reflect the activities of field personnel and support services associated with
19 field activities. O&M loaders are applied to the direct O&M costs to reflect a proportional share of
20 the indirect costs associated with field activity labor. O&M loaders represent indirect costs, and

⁷ Peak Month is defined as December. *See* Chapter 2 (Martinez).

⁸ The MDM for Medium Pressure Distribution is peak day demand. The MDM for High Pressure Distribution is peak month demand.

⁹ D.92-12-058 adopted the regression methodology and has since been utilized in every subsequent cost

1 include pension and benefits, general plant, and other costs that support the direct labor costs. The
2 O&M loading factors are applied to the direct O&M costs to develop fully-loaded O&M costs for
3 each customer class. The O&M loading factors are using 2024 FERC data. Fully-loaded O&M
4 costs are added to the marginal capital costs to derive the marginal unit cost for each functional
5 category.

6 **SOCALGAS LRMC STUDY AND COST ALLOCATION**

7 **V. SOCALGAS CUSTOMER-RELATED MARGINAL UNIT COST**

8 Customer-related marginal unit cost reflects the cost of a customer's access to the gas
9 utility's supply system,¹⁰ and is comprised of: (1) the marginal capital cost of service lines and
10 MSAs; (2) the marginal direct O&M costs associated with the installation and service of those
11 assets, as well as other customer support functions; and (3) O&M loaders. Each of these
12 components are discussed next.

13 **A. Marginal Capital Cost**

14 Marginal capital cost reflects the facilities and equipment for MSAs and service lines. For
15 residential, the capital costs are adjusted to zero. Starting July 1, 2023, Residential New
16 Construction Builders no longer receive allowances for natural gas line extensions.¹¹ Small core
17 commercial and industrial customers, marginal capital costs are calculated using the actual new
18 customer hookups in SoCalGas's service territory using the recent five years of available data (2017
19 - 2021). For other customer classes, all customers, not just new customers, belonging to a specific
20 customer class are used to estimate marginal capital costs for MSAs and service lines because of
21 low customer growth rates and the large variations in meter costs for these customers.

allocation proceeding to my knowledge.

¹⁰ D.92-12-058 at 38.

1 **1. MSA Costs**

2 MSA costs include the cost of the meter, regulator, and other equipment required in hooking
3 up a new customer and the direct labor cost for installing the equipment. The marginal costs of
4 MSAs have been derived in the following manner:

- 5 a) Extracted meter size, type, and service pressure level information, at the
6 customer level, from SoCalGas’s Customer Information System;
- 7 b) Applied actual 2021 MSA cost data for the various meter sizes, types, and
8 service pressure levels to MSA configurations at the customer level; and
- 9 c) Derived customer class-specific marginal MSA costs as the weighted
10 average MSA costs for all customers in each customer class.

11 **2. Service Line Costs**

12 The marginal costs of service lines have been derived as follows:

- 13 a) Extracted service line lengths, pipe types, and pipe diameter data, at the
14 customer level;
- 15 b) Applied unit cost data by pipe type and diameter to the average length of
16 service lines for each customer in the various customer classes. The service
17 line history are based on 2017 - 2021 data from Gas Distribution. The
18 service unit costs were escalated for labor and nonlabor overheads;¹² and

¹¹ SoCalGas Rule No. 20, C2, SDG&E Rule No. 15, C3.

¹² For new service lines and meters, I took into consideration Line Extension Allowance, per SoCalGas’s Rule 20.

1 c) Derived customer class-specific marginal service line costs as the
2 average service line costs for all customers in each customer class.

3 **B. Marginal Direct O&M Costs**

4 Customer-related marginal O&M costs are broken into five components: (1) customer
5 services, (2) customer accounts, (3) meters and regulators, (4) service lines, and (5) O&M loaders.
6 The first four components comprise the total direct O&M costs, which are based on 2021 recorded
7 O&M expenses.

8 **1. Customer Services O&M Costs**

9 Customer Services O&M costs include the field services' recorded expenses associated with
10 the O&M of SoCalGas-owned equipment, as well as inspection and service of customer-owned
11 appliances. Customer Services activities and the associated costs result from responses to customer
12 service requests and company-generated work orders, including investigating reports of potential
13 gas leaks and responding to other emergencies, establishing/terminating gas service, conducting
14 customer appliance checks, shutting off and restoring gas service for fumigations, performing meter
15 and regulator changes, inspecting meter sets for atmospheric corrosion and remediating conditions
16 found during the inspections, and other related services at customer premises. Requests are
17 categorized into general order types for which both frequency and duration are recorded. Costs also
18 include support costs associated with related field activities, such as field order dispatch costs, staff
19 and supervision costs, communication costs, as well as an allocation of vehicle, tools, and uniform
20 costs.

21 Orders are apportioned to customers and customer classes using data from SoCalGas's
22 Customer Services dispatching system, the Portable Automated Centralized Electronic Retrieval
23 (PACER) system. The Data Analysis Reporting Tools (DART) system tracks orders by time to
24 complete each activity by customer class.

1 Customer Services O&M costs are recorded in Federal Energy Regulatory Commission
2 (FERC) Functional Accounts 870, 878, and 879. These costs are allocated across customer classes
3 at each functional account level based on either the total time to complete the orders or the total
4 order volume. Functional Account 879.010 (Customer Services Field) is the largest customer
5 services account. These costs are allocated across customer classes based on the field time recorded
6 for each customer class.

7 **2. Customer Accounts O&M Costs**

8 Customer Accounts O&M costs include the recorded expenses incurred to receive calls from
9 customers requesting service, obtain monthly-metered gas consumption data from non-automated
10 meters, calculate and reconcile billing information, print and mail gas bills and collection notices to
11 customers, respond to inquiries related to billing and collections, perform collection activities, and
12 process customer payments.

13 Customer Accounts O&M costs are booked to FERC Accounts 901 through 905. Customer
14 Resource Center activity, which is recorded in FERC Accounts 903.101 and 903.107, is one of the
15 largest components of Customer Accounts O&M. This includes field service calls, customer
16 account inquiries, and general customer inquiries. The associated costs are allocated among
17 customer classes based on the number of accounts and the weighted call volumes. Field orders are
18 further tracked by type of activity (e.g., turn-on requests) and customer class.

19 Meter reading costs, which are recorded in FERC Account 902, a component of Customer
20 Accounts O&M, are substantially low with the deployment of Advanced Meter Infrastructure
21 (AMI) for core customers. The costs associated with manually reading core meters are allocated
22 based on the weighted read times for core customers. The costs associated with the daily collection
23 of electronic measurement for noncore customers are allocated by the number of noncore active
24 meters.

1 Bill distribution and remittance costs are for postage and remittance processing costs and are
2 recorded in FERC Account 903.700. The allocation of these costs across customer classes is
3 performed based on the number of active customer accounts.

4 Office credit and collections and field collections costs are for costs associated with active
5 and closed collections processing which include the following activities: following up on delinquent
6 accounts, investigating fraudulent activity, skip tracing of unpaid closed accounts, postage costs for
7 mailing collections notices, handling bankruptcies/receivership/probates, and collection of non-gas
8 payments. These costs are recorded in FERC Account 903.104. FERC Account 903.105 reflects
9 costs incurred for field collection activity that involves either collecting the delinquent amount due
10 or terminating gas services. The allocation of these costs across customer classes is performed
11 based on the number of field orders. In 2021, these costs are low due to the COVID_19 Relief
12 Payment Plan.

13 Supervision and staff support costs (FERC Accounts 903.1 and 905) are allocated based on
14 the activities supported. For example, Account 903.100 is an allocation of all related line and staff
15 functions, including billing, meter reading, the Customer Resource Center, and branch services.
16 The total allocation for these various functions is used to develop the allocator for supervision of
17 these functions.

18 **3. Meters and Regulators O&M Costs**

19 Meters and Regulators O&M costs include repair of MSAs and meter guards. Meters and
20 Regulators O&M costs are allocated based on two allocation methods. First, costs that are common
21 to all customer segments are allocated according to each customer segment's share of total
22 connected meters in service. Second, costs specifically identifiable as meter repair and replacement
23 are allocated based on each customer segment's share of the total number of meter repairs and
24 replacements during the year.

1 **4. Service Lines O&M Costs**

2 Service maintenance work is generally corrective in nature and is required to keep the
3 natural gas system operating safely and reliably. Service Lines O&M costs are allocated to each
4 customer class based on each class’s share of total service line footage at year end 2021.

5 **5. Customer Services and Information Costs**

6 Customer Services and Information costs are for activities which include account
7 management services to nonresidential and residential customers; products and services for
8 homebuilders and developers; services for capacity, pipeline, and storage; gas transmission
9 planning; gas sustainability; environmental affairs; biofuels market development; clean energy
10 innovations; and customer research, outreach, communication, and education and are booked to
11 FERC Accounts 907 through 910. These costs are broken down between market segments and
12 allocated by the number of customers. The exception is the Energy Markets costs, which are
13 broken down by staff responsibilities.

14 **C. Calculation of Customer-Related Marginal Unit Cost and Marginal Cost**
15 **Revenue**

16 The marginal unit cost for Customer-related costs (MUC_C) for capital and O&M is
17 calculated as follows:

18
$$MUC_C (\$/customer) = [CAPEX^{13} \text{ per customer } \times RECC^{14}\%] + [fully \text{ loaded O\&M}]$$

19 Once the MUC_C is calculated, then for each customer class, the marginal cost revenue (MCR) is
20 then calculated as follows:

21
$$Customer\text{-related MCR } (\$) = MUC_C \times \# \text{ of customers}$$

22

¹³ CAPEX refers to capital expenditures for marginal MSA and service line capital costs.

¹⁴ RECC refers to real economic carrying charge described in Section VII below. RECC is applied to annualize marginal capital costs.

Table MSP-1 below shows the total MUC_C for each customer class.

Table MSP-1					
Calculation of Marginal Customer Costs					
2027 \$/Customer					
Customer Class	CAPEX \$/customer	RECC %	Annualized CAPEX (\$/customer/year)	O&M and Loaders (\$/customer/ year)	Marginal Unit Cost 2024 (\$/customer/ year)
Residential	\$0.00		\$0.00	\$106.32	\$106.32
Core C/I ¹⁵	\$16,092.55	6.98%	\$1,123.24	\$555.92	\$1,679.16
Gas A/C ¹⁶					
Gas Engine ¹⁷	\$269,069.90	6.79%	\$18,279.37	\$1,015.02	\$19,294.39
NGV	\$229,873.20	7.58%	\$17,423.40	\$20,617.22	\$38,040.62
Noncore C/I ¹⁸	\$755,145.54	7.28%	\$54,981.81	\$18,527.91	\$73,509.72
Small EG ¹⁹	\$379,253.54	7.33%	\$27,807.46	\$8,022.30	\$35,829.76
Large EG ²⁰	\$2,219,865.48	8.05%	\$178,778.01	\$28,327.74	\$207,105.74
EOR ²¹	\$944,927.05	7.81%	\$73,831.43	\$26,207.01	\$100,038.45
Long Beach ²²	\$13,818,202.97	8.97%	\$1,239,598.65	\$183,864.62	\$1,423,463.27
SDG&E ²³	\$35,517,278.40	8.97%	\$3,186,171.93	\$172,611.25	\$3,358,783.18
Southwest Gas ²⁴	\$7,214,188.70	8.97%	\$647,167.99	\$227,861.02	\$875,029.00
Vernon ²⁵	\$6,900,339.96	8.97%	\$619,013.35	\$132,978.03	\$751,991.38
Ecogas ²⁶	\$1,015,578.62	8.97%	\$91,105.18	\$75,592.79	\$166,697.98

¹⁵ Core C&I are the Core Commercial & Industrial customers.

¹⁶ Gas A/C are the Gas Air Conditioning for Commercial & Industrial customers, Chapter 12, this class is being eliminated.

¹⁷ Gas Engine are Core Gas Engine Water Pumping Service for Commercial and Industrial.

¹⁸ Noncore C/I are Noncore Commercial & Industrial customers.

¹⁹ Small EG are Electric Generation customers with usage less than 3 million therms/year.

²⁰ Large EG are Electric Generation customers with usage greater than 3 million therms/year.

²¹ EOR are Enhanced Oil Refinery customers.

²² Long Beach is the Wholesale - City of Long Beach customer.

²³ SDG&E is the Wholesale – San Diego Gas & Electric customer.

²⁴ SW Gas is the Wholesale – Southwest Gas Corporation’s service territory in southern California.

²⁵ Vernon is the Wholesale – City of Vernon customer.

²⁶ Ecogas is the Wholesale – ECOGAS Mexico, S. de R.L. de C.V. customer.

1 **VI. SOCALGAS MEDIUM AND HIGH PRESSURE DISTRIBUTION-RELATED**
2 **MARGINAL UNIT COSTS**

3 Medium and High Pressure Distribution-related marginal unit costs consist of three types of
4 costs: (1) capital-related, (2) direct O&M, and (3) O&M loaders. The capital costs are recorded in
5 the plant accounts for mains (FERC Account 376) and measuring and regulating station equipment
6 (FERC Account 378). Direct O&M costs are recorded in FERC Accounts 874, 875, 887, and 889
7 for mains and measuring and regulating stations. Distribution O&M work includes maintenance on
8 mains, application of corrosion control measures, valve maintenance, regulator station maintenance,
9 checking for odorant, and locating and marking buried pipes to avoid damage caused from digging
10 by non-company individuals or entities.

11 SoCalGas develops separate marginal costs for Medium Pressure Distribution and High
12 Pressure Distribution functions because the cost drivers are different between the two functions.

13 **A. Medium Pressure Distribution Marginal Unit Cost and Marginal Cost**
14 **Revenue**

15 The marginal unit cost for Medium Pressure Distribution consists of: (1) an annualized
16 capital-related cost (or marginal capital cost), and (2) fully-loaded marginal O&M cost.

17 **1. Marginal Capital Cost**

18 The marginal capital cost is developed using a linear regression model, recognizing that
19 peak day demand is the MDM or cost driver for the Medium Pressure Distribution system. The
20 regression analysis establishes the causal relationship between cumulative load growth-related
21 capital investment in the Medium Pressure Distribution system (the dependent variable²⁷) and
22 cumulative peak day demand growth (the independent variable²⁸).

²⁷ The dependent variable represents the output or outcome whose variation is being studied.

²⁸ The independent variables represent inputs or causes, i.e., potential reasons for variation.

1 Load growth-related investments include new business, pressure betterment, and meter and
 2 regulating station investments. The period for the regression analysis is 15 years: ten years of
 3 historical data (2015 - 2024) and five years of forecast data (2025 - 2029). The demand numbers
 4 have been updated to reflect historical and forecast data. The CAPEX represents the data from the
 5 last CAP, for years 2025 to 2029 using escalation of 3% per year.²⁹ The numbers are shown as
 6 2027 dollars. The resulting estimated regression coefficient of the independent variable represents
 7 the marginal capital cost.

8 The cumulative peak day demand growth is calculated based on the net positive change in
 9 the number of customers per year multiplied by the average peak day demand per customer for each
 10 class. Table MSP-2 below shows the cumulative peak day demand and the cumulative load
 11 growth-related capital investment in the Medium Pressure Distribution system.

12 **Table MSP-2**

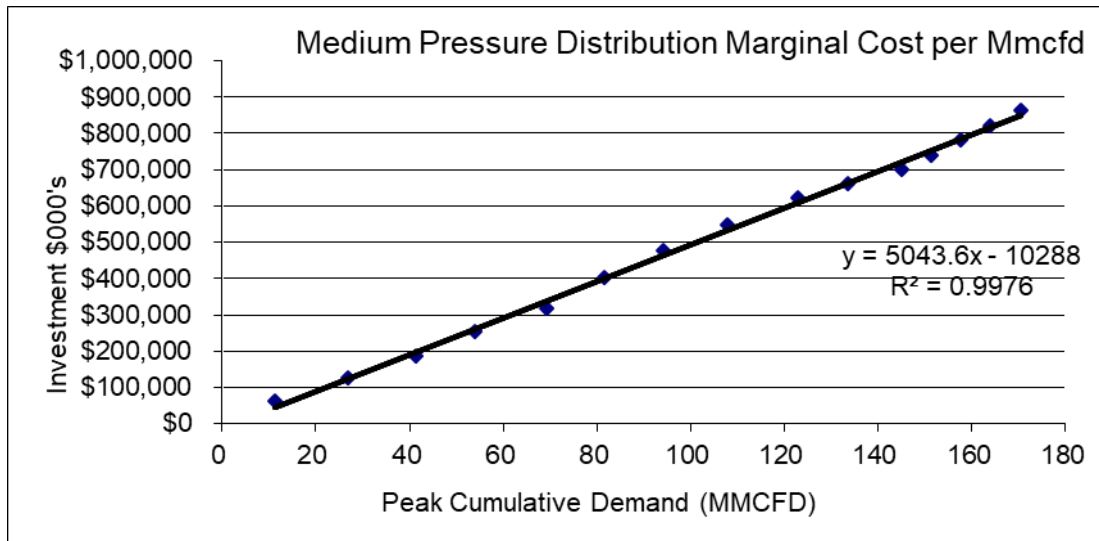
Year	Cumulative MMcfd	Cumulative CAPEX \$000's
2015	11	\$63,738
2016	27	\$127,575
2017	41	\$186,890
2018	54	\$252,556
2019	69	\$317,615
2020	81	\$401,394
2021	94	\$475,861
2022	108	\$547,792
2023	123	\$621,584
2024	133	\$660,693
2025	145	\$700,330
2026	151	\$740,511
2027	158	\$781,253
2028	164	\$822,572
2029	170	\$864,485

13 The regression analysis results are depicted in Figure MSP-1 below.

²⁹ D.24-12-074 at 895-902.

1

Figure MSP-1



2

3

2. Marginal Direct O&M Costs

4

The 2024 recorded direct O&M costs are allocated between Medium Pressure and High Pressure Distribution systems based on the split in total distribution capital investment between those two systems. Direct O&M costs are booked to FERC Accounts 874, 875, 887, and 889.

7

8

3. Calculation of Medium Pressure Distribution Marginal Unit Cost and Marginal Cost Revenue

9

The calculation of marginal unit cost for Medium Pressure Distribution (MUC_MPD) is as follows:

10

11

$$MUC_MPD (\$/Mcf^{30}) = [CAPEX \text{ per } Mcfd \times RECC\%] + [fully \text{ Loaded } O\&M]$$

12

Once the MUC_MPD is calculated for each customer class, the marginal cost revenue (MPD_MCR) is then calculated as follows:

13

14

$$MPD_MCR (\$) = MUC_MPD \times Mcfd$$

15

Table MSP-3 shows the calculation of the MUC_MPD. Marginal Cost Revenue is presented in Section VIII.

16

³⁰ Mcfd is a unit of measurement for gas representing a thousand cubic feet per day.

1
2
3
4
5
6
7
8
9
10
11
12
13

Table MSP-3

Marginal Cost for Medium Pressure Distribution (MPD) (2027 \$/Mcf peak day)	
Capital-related Charge:	
MPD Regression Coefficient \$/Mcf	\$5,043.62
x RECC Factor	6.89%
= Annualized Capital-related Charge (\$/Mcf)	\$347.65
+ Direct O&M	\$17.87
+ A&G	\$8.38
+ GP	\$8.03
+ M&S	\$0.68
= Marginal Unit Cost (\$/Mcf)	\$382.61

B. High Pressure Distribution Marginal Unit Cost and Marginal Cost Revenue

The methodology for calculating the marginal capital-related cost for the High Pressure Distribution system is analogous to the methodology used for the Medium Pressure Distribution system. Cumulative load growth-related investment costs in the High Pressure Distribution system are regressed against cumulative load growth. The coincident peak month demand served off the High Pressure Distribution system is used as the measure of MDM or cost driver for the HPD system. The demand numbers have been updated to reflect historical and forecast data. Table MSP-4 below shows the cumulative coincident peak month demand and the cumulative load growth-related capital investment in the High Pressure Distribution system.

1

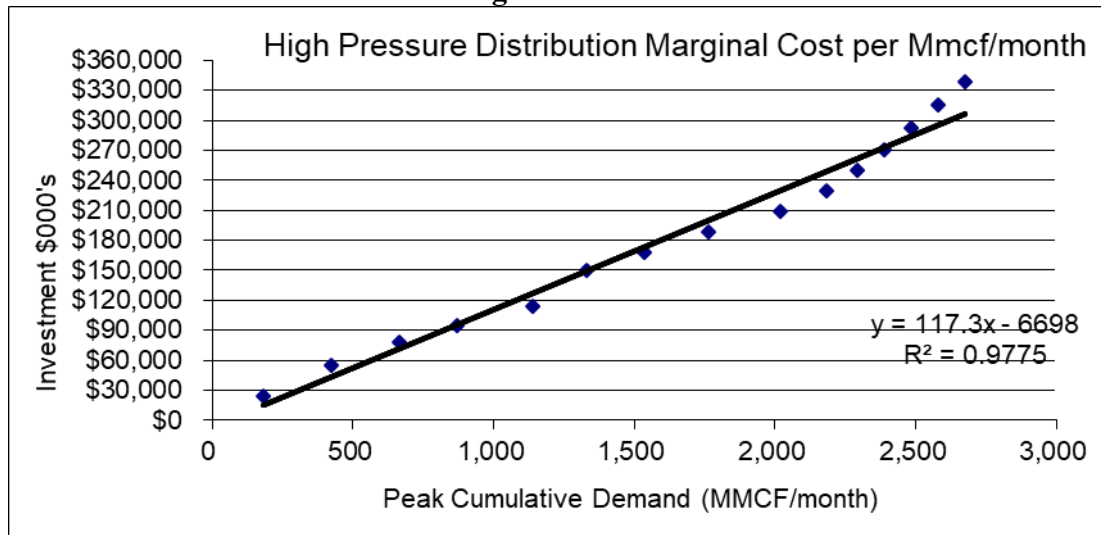
Table MSP-4

Year	Cumulative Mmcf/month	Cumulative CAPEX \$000's
2015	182	\$23,472
2016	422	\$54,819
2017	663	\$78,408
2018	869	\$94,278
2019	1,139	\$113,417
2020	1,330	\$150,096
2021	1,534	\$167,836
2022	1,764	\$188,594
2023	2,017	\$208,859
2024	2,182	\$229,067
2025	2,293	\$249,782
2026	2,388	\$271,020
2027	2,484	\$292,797
2028	2,578	\$315,128
2029	2,674	\$338,030

2 The regression analysis results are depicted in Figure 2 below.

3

Figure MSP-2



4

5 The calculation of the marginal unit cost for High Pressure Distribution (MUC_HPD) cost is as

6 follows:

7

$$MUC_HPD (\$/Mcf/month) = [CAPEX \text{ per } Mcf/month \times RECC\%] + [fully \text{ loaded } O\&M]$$

For each customer class, the marginal cost revenue for High Pressure Distribution (HPD_MCR) is then derived as follows:

$$HPD_MCR (\$) = MUC_MPD \times Mcf/month$$

Table MSP-5 below shows the calculation of the MUC_HPDP.

Table MSP-5

**Marginal Cost for High Pressure Distribution
(2027 \$/MCF/month)**

Capital-related Charge:	
HPD Regression Coefficient \$/Mcf/month	\$117.30
x RECC Factor	6.84%
= Annualized Capital-related Charge (\$/Mcf/month)	\$8.02
+ Direct O&M	\$6.70
+ A&G	\$3.14
+ GP	\$3.01
+ M&S	\$0.25
= Marginal HP Distribution Cost(\$/MCF/month)	\$21.13

VII. SOCALGAS MARGINAL COST ESTIMATION FACTORS

A. Real Economic Carrying Charge (RECC) Factors

In the previous sections, RECC factors appeared in the calculation of marginal unit costs for customer-related costs as well as for Medium and High Pressure Distribution. RECC factors are used to convert capital investment into annualized capital costs. The LRMC Decision established the use of RECC factors in LRMC studies:

The Total Investment computes an arithmetic average by dividing the total investment during the planning horizon by the total load growth using the same period. The resulting unit marginal cost is then annualized using a Real Economic Carrying Cost (RECC) factor. The RECC capital amortization formula levelizes a stream of future payments in a manner similar to an annuity calculation but with an

1 inflation adjustment. RECC models incorporate assumptions for service life, salvage
2 value, cost of capital, inflation rates, and discount rates.³¹

3 The RECC factors used in the tables above are the weighted averages for the respective
4 Customer-related, Medium Pressure Distribution-related, and High Pressure Distribution-related
5 functional categories, and, when applied to a capital investment, produce the first year charge of a
6 series of annualized capital charges that remain constant in real terms over the life of the asset. The
7 RECC factor is a function of authorized rate of return, inflation, salvage value, book life, and tax
8 rates. Based on the differing book lives and salvage values of utility assets, separate RECC factors
9 have been developed for service lines, pressure regulators, meters, and distribution capital
10 investments.

11 SoCalGas has updated its RECC factors using inflation assumptions from Global Insight's
12 forecast, updated tax rates, and SoCalGas's discount rate of 7.67% was approved via SoCalGas's
13 Advice Letter 6207-G that allowed for Cost of Capital Mechanism (CCM) adjustment under D.08-
14 05-035. The authorized book lives and salvage values for the different investments have also been
15 updated to reflect current factors.

16 **B. O&M Loaders**

17 There are three distinct O&M loaders that are applied to direct marginal O&M costs to
18 develop the fully-loaded O&M cost for each functional category, customer costs, and distribution.
19 These loading factors reflect indirect costs for: (1) administrative and general (A&G) expenses, (2)
20 general plant, and (3) materials and supplies (M&S). The A&G and general plant loading factors
21 are percentages that are applied to the direct O&M costs for each functional category. M&S costs
22 are assigned to each functional category based on plant investment. Application of O&M loaders to

³¹ D.92-12-058 at 32.

1 direct marginal O&M costs produces fully-loaded marginal O&M cost.

2 **C. A&G Loading Factors**

3 Marginal A&G expenses and payroll taxes are combined into a single loading factor, with
4 an adjustment to reflect the exclusion of Storage-related and Transmission-related costs. The
5 loading factor derived in Table 6 below reflects the ratio of marginal A&G expenses plus payroll
6 taxes to net O&M expenses. Net O&M expenses are calculated as total O&M expenses minus the
7 sum of total production expenses,³² total A&G expenses, total transmission expenses, total storage
8 expenses and exclusions not included in the base margin.

9 Recorded 2024 A&G expenses have been classified as either marginal or non-marginal on
10 an account-by-account basis. Any costs that vary with either the size of labor force or the size of
11 plant are deemed marginal costs for this study.

**Table MSP-6
A&G Loading Factor**

Total Marginal A&G Costs \$000's	\$295,808
+ Total Payroll Taxes \$000	<u>\$60,908</u>
= Marginal A&G and Payroll Taxes \$000	\$356,716
/ Net O&M Costs \$000	\$760,282
= Marginal A&G Loading Factor as a % of O&M	46.92%

12 **1. General Plant Loading Factor**

13 Gross general plant, as reflected in FERC Accounts 390 through 398, includes general plant
14 in service as of year-end 2024 for structures and improvements, office furniture and equipment,
15 computer applications and equipment, shop and garage equipment, and communication equipment.

³² Total Production Expenses reflects gas costs.

RECC factors associated with each capital category and the amounts of gross plant in service at year-end 2024 are used to calculate a weighted average general plant accounts RECC factor. The general plant accounts RECC factor is then applied to gross general plant in service as of December 31, 2024, to derive an annualized cost for general plant. This annualized general plant cost is divided by year 2024 net O&M expenses to derive the general plant loading factor, as shown in Table 7 below. Like the A&G loading factor, the derivation of general plant loading factor excludes Storage- and Transmission-related costs.

Table MSP-7
General Plant Loading Factor

Total General Plant \$000	\$2,574,220
* Weighted Average RECC for General Plant	<u>13.28%</u>
= Annualized General Plant Costs	\$341,771
/ Net Recorded O&M Costs \$000	\$760,282
= General Plant Loading Factor as a % of O&M	44.95%

2. M&S Loading Factor

M&S is comprised of materials and supplies kept in stock for use in daily field operations and in capital projects. Examples of M&S items include pipe, valves, fittings, and safety equipment. Recorded 2024 M&S costs are allocated based on gross gas plant in each functional category. Applying an M&S loading factor is appropriate because M&S is a component of the indirect costs. Distribution M&S is further categorized as customer-related and demand-related distribution plant investment. As with the other O&M loaders for customer-related and distribution functions, Storage-related and Transmission-related M&S costs have been removed from this analysis.

The functionally allocated M&S costs are annualized using the RECC factor developed for M&S investments. The annualized M&S costs are then added to the marginal O&M costs for each

1 function to derive fully-allocated O&M costs. The Table MSP-8 below shows the functionalization
2 of the year 2024 M&S costs and the derivation of annual M&S costs for each function.

Table MSP-8
M&S Annual Costs

Function	
Customer Related \$000	\$5,191
Load Related \$000	\$5,628
Total	\$10,819

3 **VIII. RESULTS OF THE SOCALGAS COST ALLOCATION STUDIES**

4 Upon completing the cost studies to allocate costs to functional categories, SoCalGas
5 allocates each functional cost to customer classes using the following MDMs: number of customers
6 for the customer costs, peak day demand for Medium Pressure Distribution costs and peak month
7 demand for High Pressure Distribution costs. Each MDM reflects the four-year average of forecast
8 annual MDM for the years 2027- 2029, reflecting the duration of the CAP period.

9 For the customer-related functional category, Table 9 shows marginal unit costs, customer
10 counts, and marginal cost revenues by customer class on an unscaled basis. The term “unscaled”
11 refers to the sum of the marginal cost revenue for each customer class, not adjusted or “scaled” to
12 equal SoCalGas’s authorized base margin. A scalar factor is applied to adjust total marginal cost
13 revenues so that the total revenue requirement from the cost studies, both LRMC and Embedded
14 cost studies, equal the authorized base margin.

Table MSP-9
UNSCALED LONG RUN MARGINAL COST REVENUES
CUSTOMER COST

\$000's

Customer Class	Customer LRM C	Customer	Customer
	\$/customer	Count	Cost \$000's
	A	B	C
Residential	106	5,844,466	\$621,358
Core C/I	1,679	201,694	338,677
Gas A/C	10,357	0	-
Gas Engine	19,294	603	11,640
NGV	38,041	390	14,836
Total Core			\$986,510
Noncore C/I	73,510	502	36,902
Small EG	35,830	309	11,071
Large EG	207,106	57	11,805
EOR	100,038	28	2,754
Total Retail Noncore			\$62,532
Long Beach	1,423,463	1	1,423
SDG&E	3,358,783	1	3,359
Southwest Gas	875,029	1	875
Vernon	751,991	1	752
Ecogas	166,698	1	167
Total Wholesale			\$6,576
UBS	\$0	0	\$0
BTS	\$0	0	\$0
Total Noncore			\$69,108
Total SoCalGas			\$1,055,618

1 Table MSP-10 shows unscaled Medium Pressure and High Pressure Distribution marginal
2 cost revenues by customer classes. Medium Pressure Distribution costs are allocated using 1-in-35
3 peak day core / 1-in-10 cold day noncore Medium Pressure Distribution service level peak day

- 1 demand. High Pressure Distribution costs are allocated using High Pressure Distribution service
 2 level peak month demand.

Table MSP-10
UNSCALED LRMC COST REVENUES
DISTRIBUTION COSTS
 \$000's

Customer Class	Medium Pressure Distribution LRMC \$/mcf A	Medium Pressure Distribution Peak Day (mcf) B	Medium Pressure Distribution Costs \$000's C	High Pressure Distribution LRMC \$/mcf D	High Pressure Distribution Peak Month Demand (mcf) E	High Pressure Distribution Costs \$000's F
Residential	\$382.61	2,026,866	\$775,507	\$21.13	31,388,468	\$663,195
Core C/I	\$382.61	511,768	\$195,810	\$21.13	10,202,401	\$215,563
Gas A/C	\$382.61	0	\$0	\$21.13	0	\$0
Gas Engine	\$382.61	1,954	\$748	\$21.13	75,327	\$1,592
NGV	\$382.61	36,916	\$14,125	\$21.13	1,852,738	\$39,146
Total Core			\$986,189			\$919,495
Noncore C/I	\$382.61	93,784	\$35,883	\$21.13	6,599,410	\$139,436
Small EG	\$382.61	19,378	\$7,414	\$21.13	814,166	\$17,202
Large EG	\$382.61	10,129	\$3,875	\$21.13	1,535,767	\$32,449
EOR	\$382.61	31	\$12	\$21.13	629,074	\$13,291
Total Retail Noncore			\$47,185			\$202,379
Long Beach	\$382.61	0	\$0	\$21.13	0	\$0
SDG&E	\$382.61	0	\$0	\$21.13	0	\$0
Southwest Gas	\$382.61	0	\$0	\$21.13	0	\$0
Vernon	\$382.61	0	\$0	\$21.13	0	\$0
Ecogas	\$382.61	0	\$0	\$21.13	0	\$0
Total Wholesale			\$0			\$0
UBS	\$382.61	0	\$0	\$21.13	0	\$0
BTS	\$0.00	0	\$0	\$0.00	0	\$0
Total Noncore			\$47,185			\$202,379
Total SoCalGas			\$1,033,374			\$1,121,874

1 In D.92-12-058, the Commission stated that “marginal cost revenues need to be scaled to the
2 embedded-based authorized revenue requirement under our ratemaking procedures.”³³ The scalar is
3 employed to adjust the proposed marginal cost revenues to the base margin, excluding costs directly
4 allocated to the Transmission, Storage, Uncollectible,³⁴ and NGV Public Access functions. In this
5 CAP, marginal costs are scaled at a rate of 84% in order to reconcile to the base margin of
6 \$2,697,933 thousand. Table MSP-11 shows this process.

³³ D.92-12-058 at 50.

³⁴ Uncollectible (not collected revenues) are treated separately because SoCalGas’s wholesale customers do not have any uncollectibles.

Table MSP-11
LRMC COST SCALED REVENUES
SCALED CUSTOMER & DISTRIBUTION COSTS

\$000's

Customer Class	Customer Cost A	Medium Pressure Distribution B	High Pressure Distribution C	Unscaled LRMC Revenues D=A+B+C	Scalar E	Scaled LRMC Revenues F=D*E
Residential	\$621,358	\$775,507	\$663,195	\$2,060,060	84%	\$1,730,856
Core C/I	\$338,677	\$195,810	\$215,563	\$750,049	84%	\$630,189
Gas A/C	\$0	\$0	\$0	\$0	84%	\$0
Gas Engine	\$11,640	\$748	\$1,592	\$13,979	84%	\$11,745
NGV	\$14,836	\$14,125	\$39,146	\$68,106	84%	\$57,223
Total Core	\$986,510	\$986,189	\$919,495	\$2,892,195	84%	\$2,430,012
Noncore C/I	\$36,902	\$35,883	\$139,436	\$212,222	84%	\$178,308
Small EG	\$10,570	\$7,414	\$17,202	\$35,186	84%	\$29,563
Large EG	\$4,763	\$3,875	\$32,449	\$41,088	84%	\$34,522
EG Transmisson	\$7,543			\$7,543	84%	\$6,338
EOR	\$2,754	\$12	\$13,291	\$16,057	84%	\$13,491
Total Retail Noncore	\$62,532	\$47,185	\$202,379	\$312,095	84%	\$262,221
Long Beach	\$1,423	\$0	\$0	\$1,423	84%	\$1,196
SDG&E	\$3,359	\$0	\$0	\$3,359	84%	\$2,822
Southwest Gas	\$875	\$0	\$0	\$875	84%	\$735
Vernon	\$752	\$0	\$0	\$752	84%	\$632
Ecogas	\$167	\$0	\$0	\$167	84%	\$140
Total Wholesale	\$6,576	\$0	\$0	\$6,576	84%	\$5,525
UBS	\$0	\$0	\$0	\$0	84%	\$0
BTS	\$0	\$0	\$0	\$0	84%	\$0
Total Noncore	\$69,108	\$47,185	\$202,379	\$318,671	84%	\$267,747
Total SoCalGas	\$1,055,618	\$1,033,374	\$1,121,874	\$3,210,866	84%	\$2,697,759

1 After the derivation of scaled customer and distribution marginal cost revenues by customer
2 classes, the remaining base margin items for Transmission, Storage, NGV, and Uncollectible costs

1 are allocated to customer classes, as shown in Table MSP-12. Transmission and Storage are
2 escalated by 3%/year to 2027.³⁵ Local Transmission costs³⁶ are allocated to customer classes using
3 cold year peak month throughput. Backbone Transmission costs³⁷ are isolated to derive the
4 Backbone Transmission System (BTS) rate. Storage costs³⁸ are allocated to customer classes using
5 the storage rates (for inventory, injection, and withdrawal) applied to the capacities for core storage,
6 load balancing, and load balancing plus functions proposed in this CAP.³⁹ Uncollectible and NGV
7 Public Access Station costs are also included. The system average uncollectible rate is -0.375%.
8 The NGV Public Access Station cost is allocated to the NGV class for recovery through the NGV
9 Compressor Adder cost.

10 Finally, scaled LRMC costs are combined with the Transmission, Storage, Uncollectible,
11 and NGV Public Access costs to determine the proposed cost allocation of authorized base margin.
12 This is presented in Column G of Table MSP-12.

³⁵ See Chapter 8 (Seres/Schmidt-Pines). FF&U and Escalation added. D.24-12-074 at 895-902.

³⁶ See Chapter 8 (Seres/Schmidt-Pines). FF&U and Escalation added. D.24-12-074 at 895-902.

³⁷ *Id.*

³⁸ *Id.*

³⁹ See direct testimony of Michelle Dandridge (Chapter 1).

Table MSP-12
ALLOCATION OF BASE MARGIN

\$000's

Customer Class	Scaled LRM Revenues	Uncollect	BTS	Local Transmission	NGV Public Access	Storage	Allocated Base Margin
	A	B	C	D	E	F	G
Residential	\$1,730,856	\$8,563	\$0	\$110,185	\$0	\$173,439	\$2,023,043
Core C/I	\$630,189	\$3,040	\$0	\$32,256	\$0	\$43,406	\$708,891
Gas A/C	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Gas Engine	\$11,745	\$56	\$0	\$202	\$0	\$1,085	\$13,088
NGV	\$57,223	\$332	\$0	\$5,154	\$5,629	\$5,720	\$74,057
Total Core	\$2,430,012	\$11,992	\$0	\$147,798	\$5,629	\$223,649	\$2,819,079
Noncore C/I	\$178,308	\$1,306	\$0	\$34,500	\$0	\$22,757	\$236,872
Small EG	\$29,563	\$157	\$0	\$2,057	\$0	\$1,539	\$33,316
Large EG	\$34,522	\$212	\$0	\$4,245	\$0	\$2,877	\$41,857
EG							
Transmission	\$6,338	\$807	\$0	\$49,157	\$0	\$29,312	\$85,614
EOR	\$13,491	\$0	\$0	\$2,208	\$0	\$1,561	\$17,261
Retail Noncore	\$262,221	\$2,482	\$0	\$92,168	\$0	\$58,047	\$414,918
Long Beach	\$1,196	\$0	\$0	\$3,229	\$0	\$1,248	\$5,672
SDG&E	\$2,822	\$0	\$0	\$31,772	\$0	\$32,583	\$67,177
Southwest Gas	\$735	\$0	\$0	\$3,819	\$0	\$1,316	\$5,870
Vernon	\$632	\$0	\$0	\$1,725	\$0	\$1,251	\$3,608
Ecogas	\$140	\$0	\$0	\$2,827	\$0	\$2,035	\$5,002
Total Wholesale	\$5,525	\$0	\$0	\$43,371	\$0	\$38,433	\$87,330
UBS	\$0	\$0	\$0	\$0	\$0	\$35,508	\$35,508
BTS			\$502,896				\$502,896
Total Noncore	\$267,747	\$2,482	\$502,896	\$135,539	\$0	\$131,988	\$1,040,652
Total SoCalGas	\$2,697,759	\$14,474	\$502,896	\$283,337	\$5,629	\$355,636	\$3,859,731

1 **IX. COMPARISON OF SOCALGAS PROPOSED COST ALLOCATION TO CURRENT**
2 **COST ALLOCATION**

3 The following is a comparison of the proposed 2027 cost allocation to the current allocation
4 effective September, 2025. This comparison is pre-System Integration⁴⁰ and pre-BTS unbundling,⁴¹
5 as discussed in the direct testimony of Michael Foster (Chapter 12). The difference of \$198 million
6 is due to PSEP costs included in Base Margin. The PSEP costs are included in the studies and not
7 allocated separately as is in current rates.

8 Relative to the current allocation, the proposed CAP allocation of base margin across
9 customer classes shows a decrease for core customers, including residential customers, an increase
10 for noncore customers and an increase for unbundled backbone transmission service. These
11 allocation changes reflect the impacts of updated cost studies for customer-related, distribution,
12 transmission and storage functions and updated lower demand forecasts. The residential allocation
13 shows a decrease due to the residential customer-related capital costs going to zero.

⁴⁰ Shows rates pre-System Integration. Under System Integration, the costs of local transmission facilities are recovered on a common (or integrated) basis from customers of both SDG&E and SoCalGas. This integration reflects the splitting of total local transmission costs between the utilities by the % share of cold-year peak month throughput.

⁴¹ Shows allocation pre-BTS unbundling. BTS represents the costs of SoCalGas's and SDG&E's transmission lines from the California Border receipt points to SoCalGas's Citygate.

Table MSP-13
COST ALLOCATION COMPARISON

\$000's

Customer Class	Proposed Allocation of Base Margin		Current Allocation of Base Margin	
		% Total		% Total
	A	B	C	D
Residential	\$2,023,043	52.4%	\$2,280,942	62.3%
Core C/I	\$708,891	18.4%	\$538,916	14.7%
Gas A/C	\$0	0.0%	\$61	0.0%
Gas Engine	\$13,088	0.3%	\$12,599	0.3%
NGV	\$74,057	1.9%	\$40,058	1.1%
Total Core	\$2,819,079	73.0%	\$2,872,577	78.5%
Noncore C/I	\$236,872	6.1%	\$143,801	3.9%
Small EG	\$33,316	0.9%	\$22,702	0.6%
Large EG	\$41,857	1.1%	\$20,771	0.6%
EG Transmission	\$85,614	2.2%	\$61,354	1.7%
EOR	\$17,261	0.4%	\$10,281	0.3%
Total Retail Noncore	\$414,918	10.7%	\$258,910	7.1%
Long Beach	\$5,672	0.1%	\$5,285	0.1%
SDG&E	\$67,177	1.7%	\$59,347	1.6%
Southwest Gas	\$5,870	0.2%	\$4,417	0.1%
Vernon	\$3,608	0.1%	\$3,576	0.1%
Ecogas	\$5,002	0.1%	\$4,234	0.1%
Total Wholesale	\$87,330	2.3%	\$76,859	2.1%
UBS	\$35,508	0.9%	\$30,850	0.8%
BTS	\$502,896	13.0%	\$422,225	11.5%
Total Noncore	\$1,040,652	27.0%	\$788,844	21.5%
Total SoCalGas	\$3,859,731	100.0%	\$3,661,421	100.0%

1 **SDG&E LRM STUDY AND COST ALLOCATION**

2 **X. SDG&E CUSTOMER-RELATED MARGINAL COSTS**

3 Customer-related marginal unit cost reflects the cost of a customer’s access to the gas utility’s
4 supply system and is comprised of: (1) the marginal capital cost of service lines and meter set
5 assemblies; (2) the marginal direct O&M costs associated with the installation and service of those
6 assets, as well as other customer support functions; and (3) O&M loaders.

7 **A. Marginal Capital Costs**

8 Service line, regulator, and meter (SRM) costs reflect the capital expense associated with
9 providing customer access to the gas supply system. These costs include gas meters, regulators,
10 pipes, and installation labor. For residential, the capital costs are adjusted to zero. Starting July 1,
11 2023, Residential New Construction Builders no longer receive allowances for natural gas line
12 extensions.⁴² The SDG&E Gas Distribution Engineering Department provides updated customer
13 data, including:

- 14 • Meter size, type, regulator, fitting costs and installation costs;
- 15 • Service footages;
- 16 • Service costs for new hook-ups and replacements;
- 17 • Costs of service line installations; and
- 18 • Series of flow ranges,⁴³ and corresponding equipment profiles, at each range.

19 Twenty-six flow ranges are identified for which SRM costs are summarized. These total capital
20 costs are annualized using corresponding Real Economic Carrying Charge factors, which I discuss

⁴² SoCalGas Rule No. 20, C2, SDG&E Rule No. 15, C3

⁴³ The SDG&E Gas Distribution Engineering Department defines flow ranges to specify typical meter and regulator equipment design flow capacity used to support different levels of gas flow.

1 in Section VI. The annualized costs are multiplied by the number of meters for each customer class
 2 represented within each flow range to determine the total annual capital cost associated with serving
 3 each class. Finally, the total annualized capital cost is divided by the forecast number of customers
 4 in each class to determine each class's average marginal SRM cost. Table MSP-14 shows the
 5 resulting 2027⁴⁴ annualized marginal capital-related costs per customer.

Table MSP-14	
CUSTOMER-RELATED LRMC - CAPITAL COSTS	
Customer Class	Rental-Method Customer Cost (2027 \$/customer)
Residential	\$0
Core Commercial/Industrial	\$379
Natural Gas Vehicle	\$1,191
Noncore Commercial/Industrial	\$2,115
Small Electric Generation	\$942
Large Electric Generation	\$2,245

6 **B. Marginal Direct O&M Costs**

7 Customer Services direct O&M expenses are accounted for in FERC Accounts 901-905 and
 8 907-910 and are allocated entirely as Customer-related function. These expenses are associated
 9 with responding to customer service field orders and generally operating and maintaining service
 10 lines, meters, and house regulators. FERC Accounts 870-894 record Distribution O&M. These
 11 expenses are associated with the maintenance of customers' meters, regulators, and service lines, as
 12 well as distribution mains.
 13

⁴⁴ Escalation factors updated to reflect S&P Global Handy Whitman 4th Quarter utility cost forecast, released January 2025.

1 Distribution O&M costs are assigned to market segments by classifying the costs as either
2 Customer-related or Medium Pressure and High Pressure Distribution-related. Customer-related
3 distribution O&M is allocated entirely to the Customer-related function. These activities include
4 meter reading, customer services, credit collections, and billing services. The Medium and High
5 Pressure Distribution-related expenses are allocated between the High Pressure Distribution,
6 Medium Pressure Distribution, and Customer-related functions based on pipeline mileage as of
7 December 31, 2024. The SDG&E Gas Distribution Engineering Department identifies the marginal
8 portion of each of the FERC Accounts 870-894.

9 Customer-related distribution O&M is allocated to the customer classes using the effective
10 percentage of total annualized SRM investment costs. The resulting allocation of Customer-related
11 distribution O&M expenses to customer classes is combined with Customer Services O&M
12 expenses, and then divided by the number of customers in each class to determine a per-customer
13 direct O&M expense. The direct O&M costs are allocated to customer classes in three steps. First,
14 Customer Services marginal direct O&M expenses are classified into functions. Expenses by
15 Customer Services function are then assigned to one of these operational activities. Finally, these
16 expenses are allocated to customer classes based on either the operational activity performed, or the
17 market segment supported. Once Customer Services costs are allocated to the customer classes, they
18 are combined with the portion of Distribution O&M costs allocated to Customer-related function in
19 order to develop total Customer-related direct O&M costs. Table MSP-15 shows the Customer-
20 related direct O&M costs.

Table MSP-15				
CUSTOMER-RELATED DIRECT MARGINAL O&M EXPENSES (2027 \$)				
Customer Class	FERC 870-894 \$000	FERC 901- 910 \$000	Customers per Class	Direct O&M \$/Customer
Residential	\$57,770	\$1,029	886,131	\$66
Core Commercial/Industrial	\$4,822	\$36	30,662	\$158
Natural Gas Vehicle	\$19	\$0.0	36	\$516
Noncore Commercial/Industrial	\$52	\$8	67	\$902
Small Electric Generation	\$32	\$11	91	\$475
Large Electric Generation	\$11	\$1	9	\$1,397

1 **C. O&M Loaders**

2 Three distinct O&M loaders are applied to direct marginal O&M costs to develop the fully
3 loaded O&M. These loading factors reflect indirect costs for: (1) administrative and general (A&G)
4 expenses, (2) general plant, and (3) materials and supplies (M&S), as discussed in Section XII
5 below. The A&G and general plant loading factors are percentages that are applied to the direct
6 O&M costs for each functional category. M&S costs are assigned to each functional category
7 based on plant investment. Application of O&M loaders to direct costs produces a fully loaded
8 marginal unit cost.

9 **D. Fully Loaded Customer-Related LRMC**

10 Table MSP-16 provides the total marginal customer costs for the six SDG&E customer
11 classes. These costs are the result of combining the fully loaded O&M costs with the capital related
12 costs from Table 1. The fully loaded O&M costs include direct O&M and O&M loaders. The
13 noncore customer classes post significantly higher marginal costs per customer than the core
14 customer classes because noncore customers have much higher gas service demands and require
15 larger and more specialized metering and service facilities compared to core customers.

Table MSP-16						
CUSTOMER-RELATED LONG RUN MARGINAL COSTS						
(2027 \$/customer)						
Customer Class	Annualized Capital Cost	Expense-Related O&M				Total \$/Customer
		Direct	M&S	A&G	General Plant	
Residential	\$0	\$66	\$1	\$17	\$14	\$99
Core Commercial/Industrial	\$379	\$158	\$2	\$41	\$34	\$614
Natural Gas Vehicle	\$1,191	\$516	\$6	\$135	\$110	\$1,958
Noncore Commercial/Industrial	\$2,115	\$902	\$10	\$235	\$192	\$3,455
Small Electric Generation	\$942	\$475	\$5	\$124	\$101	\$1,647
Large Electric Generation	\$2,245	\$1,397	\$16	\$365	\$297	\$4,319

1 **XI. SDG&E MEDIUM PRESSURE AND HIGH-PRESSURE DISTRIBUTION-**
2 **RELATED MARGINAL COSTS**

3 Marginal costs are calculated for both the Medium Pressure and High Pressure Distribution
4 systems. Separate marginal costs are calculated for the Medium Pressure and High Pressure
5 Distribution systems because the marginal demand measures driving the costs for the two systems
6 are different.

7 **A. Marginal Direct O&M Costs**

8 This LRMC study utilizes ten years of historical (2015-2024) and five years of forecast
9 (2025-2029) distribution plant investments and marginal demand measures. The SDG&E Gas
10 Distribution Engineering Department provides the historical period investments from an analysis of
11 accounting data for Medium Pressure Distribution and High Pressure Distribution capital
12 investments. The forecast investments are also provided by that department. For years 2025 to
13 2029 the investment was escalated 3% per year.⁴⁵ The marginal demand measures are based on an
14 analysis of peak-day throughput⁴⁶ on the Medium Pressure Distribution and High Pressure

⁴⁵ D.24-12-074 at 895-902.

⁴⁶ Throughput is defined as the volume of gas flowing through a meter over a specified period of time.

1 Distribution systems. Marginal demand measures, including peak-day load by market segment, are
2 from the consolidated demand forecast presented in Chapter 5 (Martinez).

3 Linear regression is used to determine the marginal capital costs of the Medium Pressure
4 Distribution and High Pressure Distribution systems. This method plots the cumulative incremental
5 investment as the dependent variable against the cumulative incremental changes in peak-day
6 demand, which is the independent variable. The slope of the best-fit line is taken to be the marginal
7 capital cost. This capital cost is then annualized by using a weighted-average Real Economic
8 Carrying Charges factor applicable to Distribution Demand-related distribution pipeline
9 investments. The linear regression analysis is described in Section D below.

10 **B. Marginal Direct O&M Costs**

11 FERC Accounts 870-894 record Distribution-related O&M, and these expenses are assigned
12 to market segments by classifying the costs as either Customer-related or Distribution-related. The
13 Distribution-related expenses are allocated between the High Pressure Distribution, Medium
14 Pressure Distribution, and Customer-related functions based on pipeline mileage as of December
15 31, 2021. The SDG&E Gas Distribution Engineering Department identifies the marginal portion of
16 each of FERC Account Medium Pressure Distribution and High Pressure Distribution direct O&M
17 expenses are divided by the peak-day demand of each system to determine their respective direct
18 O&M expenses. Table MSP-17 below presents a summary of direct distribution O&M expenses by
19 market segment.

Table MSP-17			
DISTRIBUTION-RELATED DIRECT MARGINAL O&M EXPENSES			
(2027 \$)			
Distribution Function	FERC		Direct O&M \$/mcf
	870-894 \$000	Peak-day Load (mcf)	
Medium-Pressure	\$30,376	413,415	\$73.48
High-Pressure	\$1,317	340,550	\$3.87

C. O&M Loaders

A&G, general plant, and M&S loaders are applied to direct costs to produce a fully loaded marginal unit cost. The development of these loaders is described in Section VI.

D. Fully Loaded Distribution LRMC

Fully-loaded O&M costs are added to distribution marginal capital costs to determine the total marginal costs for the Medium Pressure Distribution and High Pressure Distribution systems.

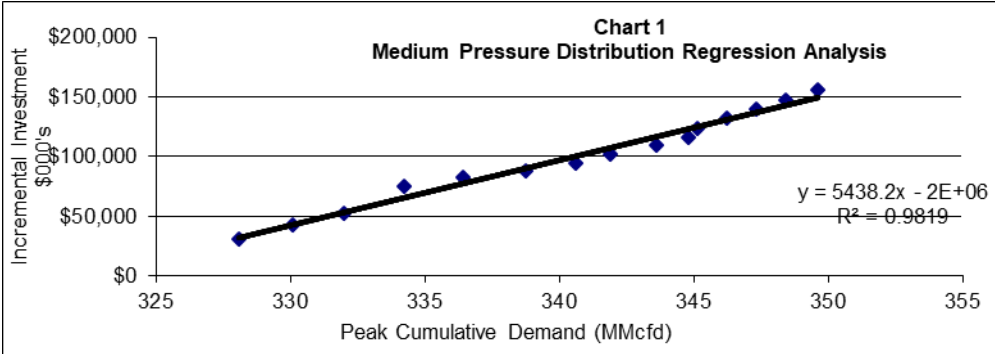
Table MSP-18 presents the total marginal costs for the Medium Pressure Distribution systems.

Table MSP-18		
MEDIUM-PRESSURE DISTRIBUTION LRMC		
(2027 \$/MCF MPD peak day)		
Marginal Investment Cost		\$5,438.21
x <u>RECC Factor</u>		<u>6.98%</u>
= Annualized Investment Cost		\$379.62
<u>Expense-Related</u>		
+ O&M Cost		\$97.63
+ A&G Cost		\$25.49
+ General / Common Plant Cost		\$20.76
+ <u>M&S Cost</u>		<u>\$2.87</u>
= Total Marginal Cost		\$526.37

1 The following chart, Figure MSP-3, depicts the results of the regression analysis in graphical form.

2

Figure MSP-3



3

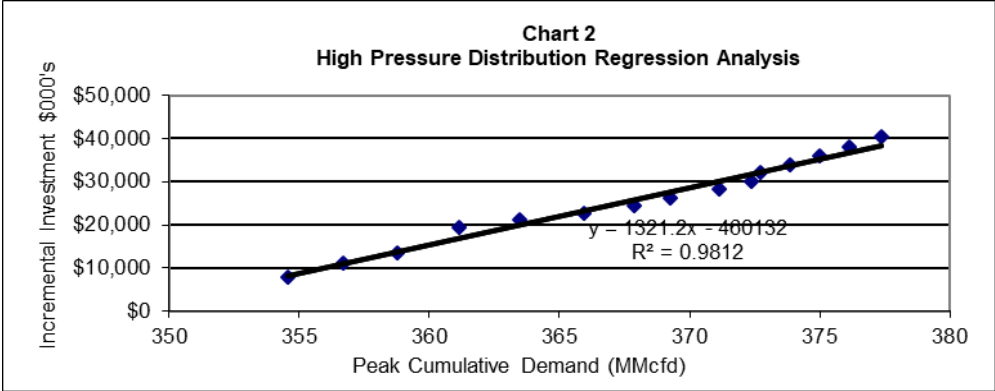
4 Table MSP-19 presents the total marginal costs for the High Pressure Distribution systems.

Table MSP-19	
HIGH-PRESSURE DISTRIBUTION LRMC	
(2027 \$/MCF HPD peak day)	
Marginal Investment Cost	\$1,321.21
x RECC Factor	<u>6.98%</u>
= Annualized Investment Cost	\$92.23
<u>Expense-Related</u>	
+ O&M Cost	\$4.07
+ A&G Cost	\$1.06
+ General / Common Plant Cost	\$0.86
+ <u>M&S Cost</u>	<u>\$0.71</u>
= Total Marginal Cost	\$98.93

5 The following chart, Figure MSP-4, depicts the results of the regression analysis in graphical form.

6

Figure MSP-4



7

1 **XII. SDG&E MARGINAL COST ESTIMATION FACTORS**

2 **A. Real Economic Carrying Charges (RECC)**

3 In the previous sections, RECC factors appeared in the calculation of marginal unit costs for
4 customer-related costs as well as Medium Pressure and High Pressure Distribution capital costs.
5 RECC factors are used to convert capital investment into annualized capital costs.⁴⁷

6 The RECC factors used in Tables MSP-14, MSP-16, MSP-18 and MSP-19 are the weighted
7 averages for the respective Customer-related, Medium Pressure Distribution-related, and High
8 Pressure Distribution-related functional categories, and, when applied to a capital investment,
9 produce the first year charge of a series of annualized capital charges that remain constant in real
10 terms over the life of the asset. The RECC factor is a function of authorized rate of return,
11 inflation, salvage value, book life, and tax rates. Based on the differing book lives and salvage
12 values of utility assets, separate RECC factors have been developed for service lines, pressure
13 regulators, meters, and distribution capital investments. SDG&E has updated its RECC factors
14 using inflation assumptions from Standard and Poor (S&P)'s forecast, updated tax rates, and
15 SDG&E's authorized rate of return of 7.67% revised per Advice Letter No. 3239-G.⁴⁸ The
16 authorized book lives and salvage values for the different investments have also been updated to
17 reflect current factors.

18

⁴⁷ Refer to Section VI, *supra*.

⁴⁸ SDG&E's Cost of Capital Mechanism (CCM) Trigger Adjustment Effective January 1, 2024, Pursuant to D.22-12-031.

1

Table MSP-20	
REAL ECONOMIC CARRYING CHARGE FACTORS	
Cost Type	RECC %
Meters and Regulators	7.69%
Meter/Regulator Installation	8.04%
Service Line Pipe	6.98%
Weighted-Average Distribution	6.98%
Materials and Supplies	9.85%
Weighted-Average General/Common Plant	7.07%

2

B. Marginal O&M Loading Factors

3

Loading factors account for costs related to A&G expenses and payroll taxes, general plant, and M&S. SDG&E derives loading factors using the same methodology adopted in the 2020 TCAP application, A.18-07-024. The A&G and general plant loading factors are percentages that are applied to the direct O&M costs for each functional category. M&S costs are assigned to each functional category based on plant investment. Application of O&M loaders to direct costs produces fully loaded marginal O&M costs.

9

1. A&G Loading Factor

10

A&G refers to operational expenses that are not directly associated with the production of any good or service and include items such as rent and insurance. Marginal A&G expenses and payroll taxes are combined into a single loading factor. I relied on the recorded year 2024 A&G expenses from the Annual Report, which are then classified as either marginal or non-marginal by account. As shown below in Table MSP-21, the proposed A&G expenses and payroll tax loader is 26.11%. The A&G loading factor is calculated as a percentage of total O&M (less A&G) and then multiplied by the direct O&M unit cost for each function.

16

1

Table MSP-21 A&G LOADING FACTOR	
Account Description	Marginal Costs 2027 \$ 000s
A&G Expenses	\$30,102
+ <u>Payroll Taxes</u>	<u>\$6,731</u>
= Total A&G with Payroll Taxes	\$36,833
/ <u>Total O&M Expenses excluding A&G</u>	<u>\$141,078</u>
= A&G Loading Factor	26.11%

2

2. General Plant Loading Factor

3

General plant includes structures and improvements, office furniture and equipment,

4

computer applications and equipment, shop and garage equipment, and communication equipment,

5

as well as plant shared between SDG&E electric and gas operations allocated to the gas function.

6

The recorded year 2024 general plant⁴⁹ total is multiplied by the weighted-average RECC factor of

7

7.07% to obtain an annualized general plant of \$58.8 million. The general plant loading factor is

8

then determined by dividing annualized general plant by total O&M expenses. Table MSP-22

9

shows the derivation of the general plant loading factor.

10

⁴⁹ Total 2021 General Plant of \$831,562 thousand is the sum of Total General Plant of \$32,339 thousand (source: 2024 SDG&E FERC Form 2) and Common Utility Plant – Gas of \$799,223 thousand (source: 2024 SDG&E Gas FERC Form 1).

1

Table MSP-22	
GENERAL PLANT LOADING FACTOR	
Account Description	2024 Recorded Costs 2027 \$ 000s
Total General Plant	\$831,562
+ <u>Average General Plant RECC</u>	<u>7.07%</u>
= Annualized General Plant	\$58,791
/ <u>Total O&M Expenses</u>	<u>\$276,485</u>
= General Plant Loading Factor	21.26%

2

3. M&S Loading Factor

3

4

5

6

7

8

9

10

11

12

13

M&S includes those materials in stock for use in company operations. Examples of M&S items include pipe, valves, fittings, and safety equipment. Recorded year 2024 M&S costs of \$21.2 million are allocated to the functions based on percentage of gross plant in each functional category and then multiplied by a factor of 9.85% to obtain annualized M&S costs. M&S costs allocated to the customer cost function are further allocated to the customer classes at the same relative percentage as direct O&M. M&S loaders are then derived by dividing allocated M&S costs by the number of customers in each class. For the Distribution functions (i.e., Medium Pressure Distribution-related and High Pressure Distribution-related), allocated M&S costs are divided by peak-day load in order to determine the loader amounts. Table MSP-23 presents the resulting M&S loading costs by customer class and function.

1

Table MSP-23			
M&S LOADING FACTORS			
(2027 \$)			
Customer Class	Allocated M&S	Customers per Class	M&S Loader \$/Customer
Residential	\$661,455	886,131	\$0.75
Core Commercial/Industrial	\$54,650	30,662	\$1.78
Natural Gas Vehicle	\$209	36	\$5.81
Noncore Commercial/Industrial	\$680	67	\$10.15
Small Electric Generation	\$486	91	\$5.34
Large Electric Generation	\$141	9	\$15.71
Distribution Function	Allocated M&S	Peak-day Load (mcf/d)	M&S Loader \$/mcf/d
Medium-Pressure	\$892,142	413,415	\$2.16
High-Pressure	\$230,433	340,550	\$0.68

2 **XIII. SDG&E ALLOCATED BASE MARGIN**

3 Upon completing the cost studies to allocate costs to functional categories, SDG&E
4 allocates each functional cost to customer classes using the marginal demand measures: number of
5 customers for the customer costs and peak day demand for both Medium Pressure Distribution costs
6 and High Pressure Distribution costs. Each marginal demand measure reflects the forecast annual
7 average marginal demand measures (listed above) for the years 2027 - 2029, reflecting the duration
8 of the 2027 TCAP period.

9 For the Customer-related functional category, Table MSP-24 shows marginal unit costs, the
10 customer counts, and the marginal cost revenues by customer classes on an unscaled basis. The
11 term “unscaled” refers to the sum of the marginal demand measures multiplied by the marginal unit
12 costs for each customer class, not adjusted or “scaled” to equal SDG&E’s authorized base margin.
13 A scalar factor is applied to adjust total marginal cost revenues so that the total revenue requirement
14 from both the LRMC and embedded cost studies equal the authorized base margin.

Table MSP-24			
UNSCALED LONG RUN MARGINAL COST			
CUSTOMER COST			
Customer Class	Customer LRM \$/customer	Customer Count	Customer Cost \$000's
	A	B	C
Residential	\$99	898,254	\$88,509
Core C/I	\$614	30,723	\$18,872
NGV	\$1,958	36	\$70
Total Core			\$107,452
Noncore C/I	\$3,455	67	\$231
Small EG	\$1,647	86	\$142
Large EG	\$4,319	13	\$56
Total Noncore			\$429
Total SoCalGas			\$107,881

1 Table MSP-25 shows the allocation of unscaled Medium Pressure Distribution and High
2 Pressure Distribution Marginal Cost Revenues by customer classes. Medium Pressure Distribution
3 costs are allocated using 1-in-35 peak day core / 1-in-10 cold day noncore Medium Pressure
4 Distribution service level peak day demand. High Pressure Distribution costs are allocated using 1-
5 in-35 peak day core / 1-in-10 cold day noncore High Pressure Distribution service level peak day
6 demand.
7

1

Table MSP-25						
UNSCALED LONG RUN MARGINAL COST						
DISTRIBUTION COSTS						
Customer Class	MPD LRMC \$/mcf	MPD Peak- Day (Mcf)	MPD Costs \$000	HPD LRMC \$/mcf	HPD Peak- Day (Mcf)	HPD Costs \$000
Residential	\$526	199,189	\$104,847	\$99	199,216	\$19,709
Core C/I	\$526	87,547	\$46,082	\$99	88,410	\$8,747
NGV	\$526	5,617	\$2,957	\$99	9,749	\$964
Total Core			\$153,886			\$29,420
Noncore C/I	\$526	11,300	\$5,948	\$99	11,996	\$1,187
Small EG	\$526	5,287	\$2,783	\$99	7,617	\$754
Large EG	\$526	987	\$520	\$99	7,601	\$752
Total Noncore			\$9,250			\$2,692
Total SoCalGas			\$163,136			\$32,112

2 In D.92-12-058, the Commission stated that marginal cost revenues need to be scaled to the
3 embedded-based authorized revenue requirement under SDG&E's ratemaking procedures. The
4 current SDG&E gas base margin for transportation rates effective September 1, 2025, is
5 \$547 million and this is the revenue requirement used to determine the scalar. The scalar adjusts
6 allocated marginal costs to the authorized base margin, excluding embedded costs directly assigned
7 to the Transmission (\$61.4 million)⁵⁰ and NGV Public Access (\$0.4 million) functions, which are
8 not scaled.

9 In this cost allocation proceeding (CAP), marginal costs are scaled at a rate of 160% in order
10 to reconcile to the adjusted base margin⁵¹ of \$470 million. Table MSP-25 shows the total
11 cumulative SDG&E costs being allocated. Finally, scaled LRMC costs are added to the

⁵⁰ Including Franchise Fees and Allowance for Uncollectible (FF&U) and escalation of 3%/year from 2024 to 2027. See D.24-12-074 at 895-902.

⁵¹ Adjusted Base Margin refers to base margin excluding non-scaled items: Backbone Transmission

1 Transmission and NGV Public Access costs to determine the cost-based allocation of authorized
 2 gas base margin of \$547 million.⁵² The total costs for SDG&E being allocated is presented in Table
 3 MSP-26.

Table MSP-26						
LONG RUN MARGINAL COST SCALED CUSTOMER AND DISTRIBUTION COSTS						
\$000's						
Customer Class	Customer Cost	Medium Pressure Distribution	High Pressure Distribution	Unscaled LRMC Revenues	Scalar	Scaled LRMC Revenues
Residential	\$88,509	\$104,847	\$19,709	\$213,065	160%	\$341,264
Core C/I	\$18,872	\$46,082	\$8,747	\$73,701	160%	\$118,046
NGV	\$70	\$2,957	\$964	\$3,992	160%	\$6,393
Total Core	\$107,452	\$153,886	\$29,420	\$290,758	160%	\$465,703
Noncore C/I - D	\$214	\$5,948	\$1,187	\$7,349	160%	\$11,771
Noncore C/I - T	\$17	\$0	\$0	\$17	160%	\$28
Small EG Distribution	\$166	\$2,783	\$754	\$3,702	160%	\$5,930
Large EG Distribution	\$6	\$520	\$752	\$1,278	160%	\$2,046
EG Transmission	\$26	\$0	\$0	\$26	160%	\$42
Total Noncore	\$429	\$9,250	\$2,692	\$12,372	160%	\$19,816
Total SDG&E	\$107,881	\$163,136	\$32,112	\$303,130	160%	\$485,519

4

5

Service (BTS) and NGV public access.

⁵² Per Chapter 8 (Seres/Schmidt-Pines), the SDG&E transmission system is 100% backbone. For the purposes of this testimony, SDG&E's \$77 million (including FF&U and escalation) in backbone transmission costs are allocated to the Backbone Transmission Service rate class. These costs will be incorporated in System Integration in Chapter 12 (Foster), which unbundles part of the combined Southern California Gas Company (SoCalGas)/SDG&E transmission system into the BTS tariff, with the remaining transmission costs being allocated to the local transmission function and, ultimately, back to the customer classes.

Table MSP-27							
ALLOCATION OF BASE MARGIN							
\$000's							
Customer Class	Scaled LRMC	+	Backbone Transmission	+	NGV Public Access	=	Unadjusted Allocated Base Margin
Residential	\$341,264		\$0		\$0		\$341,264
Core C/I	\$118,046		\$0		\$0		\$118,046
NGV	\$6,393		\$0		\$428		\$6,821
Total Core	\$465,703		\$0		\$428		\$466,131
Noncore C/I - D	\$11,771		\$0		\$0		\$11,771
Noncore C/I - T	\$28		\$0		\$0		\$28
Small EG	\$5,930		\$0		\$0		\$5,930
Large EG	\$2,046		\$0		\$0		\$2,046
EG Transmission	\$42		\$0		\$0		\$42
Total Noncore	\$19,816		\$0		\$0		\$19,816
BTS	\$0		\$61,352		\$0		\$61,352
Total SDG&E	\$485,519		\$61,352		\$428		\$547,299

2 **XIV. COMPARISON OF SDG&E PROPOSED COST ALLOCATION TO CURRENT**
3 **COST ALLOCATION**

4 Table MSP-28 shows a comparison of the proposed cost allocation to the current allocation.
5 This comparison is pre-System Integration⁵³ and pre-BTS unbundling.⁵⁴ The difference of \$15
6 million is due to PSEP costs included in Base Margin. The PSEP costs are included in the studies
7 and not allocated separately as is in current rates.

8

⁵³ Shows rates pre-System Integration. Under System Integration, the costs of local transmission facilities are recovered on a common (or integrated) basis from customers of both SDG&E and SoCalGas. This integration reflects the splitting of total local transmission costs between the utilities by the % share of cold-year peak month throughput.

⁵⁴ Shows allocation pre-BTS unbundling. BTS represents the costs of SoCalGas's and SDG&E's transmission lines from the California Border receipt points to SoCalGas's Citygate.

1 Relative to the current allocation, the proposed CAP allocation of base margin across
 2 customer classes shows a decrease for core customers, including residential customers, an increase
 3 for noncore customers (except for electric generation distribution-level customers) and an increase
 4 for unbundled backbone transmission service. These allocation changes reflect the impacts of
 5 updated cost studies for customer-related, distribution, transmission and storage functions and
 6 updated lower demand forecasts.

Table MSP-28				
COST ALLOCATION COMPARISON				
\$000's				
Customer Class	Proposed Allocation of Base Margin	% Total	Current Allocation of Base Margin	% Total
Residential	\$341,264	62.4%	\$377,156	70.9%
Core C/I	\$118,046	21.6%	\$66,501	12.5%
NGV	\$6,821	1.2%	\$2,536	0.5%
Total Core	\$466,131	85.2%	\$446,193	83.9%
Noncore C/I - D	\$11,771	2.2%	\$3,901	0.7%
Noncore C/I - T	\$28	0.0%	\$23	0.0%
Small EG	\$5,930	1.1%	\$2,845	0.5%
Large EG	\$2,046	0.4%	\$1,131	0.2%
EG Transmission	\$42	0.0%	\$37	0.0%
Total Noncore	\$19,816	3.6%	\$7,937	1.5%
Backbone Transmission	\$61,352	11.2%	\$77,685	14.6%
Total SDG&E	\$547,299	100%	\$531,815	100%

7 This concludes my prepared direct testimony.
 8

1 **XV. QUALIFICATIONS**

2 My name is Marjorie Schmidt-Pines. My business address is 555 West Fifth Street,
3 Los Angeles, California, 90013-1011. I am Senior Principal Regulatory Economic Advisor in the
4 CPUC/FERC Gas Regulatory Affairs Department for SoCalGas and SDG&E.

5 I hold a Bachelor of Science degree in Business Administration with an emphasis in
6 Accounting from California State University at Northridge, California. I have been employed by
7 SoCalGas since 1981 and have held positions of increasing responsibilities as an Accountant and
8 Senior Accountant in the Accounting & Finance department, as an Analyst and a Budget
9 Coordinator in the Gas Supply department, as a Senior Market Analyst and Market Advisor for the
10 Marketing and Customer Services departments and Principal Regulatory Economic Advisor in the
11 Regulatory Affairs Department.

12 As Senior Principal Regulatory Economic Advisor, I represent the Gas Rate Design Group
13 for both SoCalGas and SDG&E in the role of Project Manager, Senior Analyst and witness in
14 various major regulatory proceedings and filings dealing with allocating authorized revenue
15 requirements to functions and customer rate classes, developing rate design for each class,
16 calculating customer rate changes, and computing customers' bill impacts.

17 I have previously testified before the California Public Utilities Commission.